

Following is a copy of the titled regulation, into which EPA interpretations based on EPA guidance, determinations, and policy have been inserted in

double-line boxes

and suggestions that aid in avoidance of some common violations have been inserted in

single-line boxes.

The single-line boxes are suggested work practices recommended by the EPA/American Petroleum Institute(API)/Texas Mid-Continent Oil & Gas Association (TMOGA) Refinery Roundtable Workgroup of Region 6. These suggestions were singled out due to the number of violations or industry inquiries EPA Region 6 encountered in the suggested areas.

The user should be aware that these regulations may be revised from time to time and thus may differ from the copy used in this document. The dates of the most recent amendments to the regulations are included in the source description at the end of each section. At this point in time, there is no procedure in place to continuously maintain and update this document. Thus, the user should verify the regulations contained in this document are still valid before making conclusions based on this document.

40CFR60
New Source Performance Standards
Subpart J

§ 60.100 Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

EPA has indicated that the demetallization portion of a fluid catalytic cracking unit catalyst regenerator is not an affected facility under 60.100(a).

8/7/91 EPA Letter from SSCD to Weston Consultants

A refiner cannot circumvent the intent of Subpart J applicability by splitting a single stream from an amine unit into multiple trains, each of less than 20 LTD of sulfur recovery design capacity. Separate and distinct acid gas streams from separate amine units could each be eligible for the 20 LTD exemption.

6/19/92 EPA Letter from Region VI NSRS to New Mexico Environmental Department

EPA interprets, for the purposes of 60.100(a), the term “long tons per day” to mean the design capacity of a Claus sulfur recovery plant based upon the feed rate and content of hydrogen sulfide (expressed as sulfur) in the acid gas stream.

10/22/92 EPA Memo from SSCD to Region VIII Air Program Branch

It is EPA’s position that if a piece of equipment, which is listed as an “affected facility” in 60.100(a), begins combusting refinery-generated fuel gas during a period of natural gas curtailment, that piece of equipment is subject to the Subpart J requirements.

5/14/96 EPA Letter from Region VI CAED to Sun Company

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the

requirements of this subpart except as provided under paragraphs (c) and (d) of this section.

EPA has indicated that relocation of an existing unit or change in ownership of an existing unit does not constitute a “modification”, but a design modification made to permit the unit to burn liquid naphtha fuel could constitute a “modification” if there is an increase in SO₂ emissions as compared to the same unit burning natural gas.

12/5/75 EPA Memo from RAS to Region IV AHMD

EPA has indicated that relocation of an existing fluid catalytic cracking unit in which there is no physical change or change in method of operation is not a “modification” and therefore is not subject to Subpart J.

7/19/76 EPA Letter from ED to Plateau, Inc.

EPA has indicated that H₂S stripped from fuel gas to meet NSPS requirements for a new boiler can be returned to the fuel gas supply of an existing fuel gas combustion device which is not subject to the NSPS without constituting a “modification” of the existing combustion device. The additional H₂S in the fuel gas supply does not constitute a “modification” because of the exemption provided in 60.14(e). In that provision, the use of an alternative fuel or raw material is not, in itself, considered a “modification” if the source is capable of accommodating this fuel or raw material. The operator, however, is responsible for meeting any other local, state or federal emission limitations for the facility.

1/22/82 EPA Memo from DSSE to AHMD

EPA has indicated that replacing, after June 11, 1973, a reformer heater constitutes construction of a fuel gas combustion device.

3/10/87 EPA Letter from Region III to West Virginia Air Pollution Control Commission

There have been some incidents of non-compliance resulting from an operator failing to recognize that a change to fuel gas system or fuel gas combustion device has caused a previously-exempted system or device to become subject to Subpart J. It is recommended that operators use a management system to insure that Subpart J applicability is reviewed each time a change is made to a fuel gas system or a fuel gas combustion device.

8/28/97 recommendation of EPA/API/TMOGA Refinery Roundtable

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction or modification on or before January 17, 1984, is exempted from § 60.104(b).

(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction or modification on or before January 17, 1984, is exempt from this subpart.

(e) For purposes of this subpart, under § 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[43 FR 10868, Mar. 15, 1978, as amended at 44 FR 61543, Oct. 25, 1979; 51 FR 3300, July 1, 1986; 54 FR 34026, Aug. 17, 1989]

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A.

(a) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of

petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

EPA has indicated that an ethylene plant constitutes a “petroleum refinery” as defined in 60.101(a).

6/29/77 EPA Memo from DSSE to Region VI ED

EPA has indicated that a paraxylene plant constitutes a “petroleum refinery” as defined in 60.101(a).

11/9/77 EPA Memo from DSSE to Region II

EPA has indicated that an oil shale processing facility constitutes a “petroleum refinery” as defined in 60.101(a).

5/3/82 EPA Letter from DSSE to Davy McKee Corporation

EPA has indicated that a topping plant used to distill crude oil to produce fuel for a pipeline pump driver constitutes a “petroleum refinery” as defined in 60.101(a).

7/17/79 EPA Memo from DSSE to Compliance Branch

(b) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

EPA has indicated that the solid product produced by a solvent refined coal plant using a process identified as SRC I would not constitute “petroleum” as defined in 60.101(b). The liquid product produced by a solvent refined coal plant using a process identified as

SRC II would constitute "petroleum" as defined in 60.101(b). Therefore, a solvent refined coal plant using a process identified as SRC II would constitute a "petroleum refinery" as defined in 60.101(a). .

3/19/80 EPA Memo from DSSE to Region III

(c) "Process gas" means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) "Fuel gas" means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners.

EPA has indicated that refinery-generated butane and propane separated but uncondensed at a source where they are combusted would constitute "fuel gas" as defined in 60.101(d).

9/26/78 EPA Memo from DSSE to Region IV ED, and
3/22/77 EPA Memo from DSSE to AFB

EPA has indicated that ethylene produced in an ethylene plant and combusted constitutes a "fuel gas" as defined in 60.101(d).

6/29/77 EPA Memo from DSSE to Region VI ED

EPA has indicated that natural gas, when naturally produced, does not constitute "fuel gas" as defined in 60.101(d). However, any gas that is refinery-generated and combusted would constitute "fuel gas".

10/3/78 EPA Memo from DSSE to Region VI ED

(e) "Process upset gas" means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) "Refinery process unit" means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) "Fuel gas combustion device" means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

EPA has indicated that refinery pilot lights are not considered major combustion sources and, therefore, the application of Subpart J to the pilot light of a new ground flare would not be consistent with the original intent of Subpart J.

3/22/77 EPA Memo from DSSE to AFB

EPA has indicated that a gas pilot light, which supplies less than 0.5% of the heat release from an oil-fired process heater, should not be subject to Subpart J.

12/1/75 EPA Letter Memo from ACB to DSSE

EPA has indicated that flares are exempt from the SO₂ emissions standards when used during emergency malfunctions. Annual maintenance is not considered an emergency malfunction and, therefore, does not exempt fuel gas combustion devices from the SO₂ emissions standards..

6/2/92 EPA Memo from SSCD to Region VIII APB

EPA has indicated that a flare combusting refinery-generated gas vapors from a refinery loading rack constitutes a "fuel gas combustion device" as defined in 60.101(g).

9/14/92 EPA Letter from SSCD to Anderson-Mulholland and Associates

EPA has indicated that new process heaters, which are capable of burning fuel gas but which are not actually used to burn fuel gas, are not subject to Subpart J. However, if, at some future time, the fuel for the heaters is switched to fuel gas, they will be subject to Subpart J. The exemption in 60.14(e)(4) applies only to sources which were capable, prior to 6/11/73, of burning the alternative fuel.

10/3/78 EPA Memo from DSSE to Region VI ED

(h) "Coke burn-off" means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

(i) "Claus sulfur recovery plant" means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

EPA has indicated that a sulfur pit, where sulfur is stored prior to being removed from a refinery is not part of an affected facility because the pit is not part of the "vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide" (i.e., the Claus reaction). Therefore, the sulfur pit is not subject to Subpart J and the SO₂ gas stream does not have to meet the emission standards specified under 40CFR60.104.

11/13/90 EPA Letter from Region V ARD to Mobil Oil Corporation

EPA has indicated that a sulfur emission control unit, which thermally combusts H₂S in sour gas to produce SO₂, catalytically oxidizes the SO₂ to SO₃, and then reacts the SO₃ with water vapor to produce concentrated H₂SO₄, is not a "Claus sulfur recovery plant."

6/30/95 EPA Letter from METD to Wienberg, Bregeson & Neuman

(j) "Oxidation control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) "Reduction control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) "Reduced sulfur compounds" means hydrogen sulfide (H₂S), carbonyl sulfide (COS) and carbon disulfide (CS₂).

(m) "Fluid catalytic cracking unit" means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

EPA has indicated that a Thermoform catalytic cracking unit does not constitute a "fluid catalytic cracking unit."

7/18/77 EPA Letter from RPS to Mobil Oil Corporation

EPA has indicated that the NSPS for "fluid catalytic cracking units" were never envisioned to cover units with a maximum capacity of two hundred barrels per day.

3/21/77 EPA Letter from AEB to Ashland Oil

(n) "Fluid catalytic cracking unit catalyst regenerator" means one or more regenerators (multiple regenerators) which comprise that portion of the fluid catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs, and includes the regenerator combustion air blower(s).

(o) "Fresh feed" means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

(p) "Contact material" means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

(q) "Valid day" means a 24-hour period in which at least 18 valid hours of data are obtained. A "valid hour" is one in which at least 2 valid data points are obtained.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10868, Mar. 15, 1978; 44 FR 13481, Mar. 12, 1979; 44 FR 61543, Oct. 25, 1979; 45 FR 79453, Dec. 1, 1980; 54 FR 34026, Aug. 17, 1989]

§ 60.102 Standard for particulate matter.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) Particulate matter in excess of 1.0 kg/1000 kg (1.0 lb/1000 lb) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of

particulate matter emissions shall not exceed 43.0 g/MJ (0.10 lb/million Btu) of heat input attributable to such liquid or solid fossil fuel.

(Sec. 111, 114, Pub. L. 91604, 84 Stat. 1683 (42 U.S.C. 1857c6, 18579, 7414); sec. 301(a), Pub. L. 90148, 81 Stat. 504 (42 U.S.C. 1857g(a)))

[39 FR 9315, Mar. 8, 1974, as amended at 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10868, Feb. 15, 1978; 54 FR 34026, Aug. 17, 1989]

§ 60.103 Standard for carbon monoxide.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis).

[39 FR 9315, Mar. 8, 1974, as amended at 54 FR 34026, Aug. 17, 1989; 55 FR 40171, Oct. 2, 1990]

§ 60.104 Standards for sulfur oxides.

Each owner or operator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of

relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO₂) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H₂S), each calculated as ppm SO₂ by volume (dry basis) at zero percent excess air.

(b) Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

(1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (vppm), whichever is less stringent; or

(2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/1,000 kg coke burn-off; or

(3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight.

There have been some incidents of non-compliance resulting from an operator not having satisfactory documentation of the method used to demonstrate that an FCCU regenerator is in compliance with the sulfur oxides emissions limit. The calculation methods required for demonstrating compliance with 60.104(b)(1), (2), or (3) are stipulated in 60.106. It is recommended that operators insure that they have adequate documentation of the data and calculations required by the applicable portions of 60.106.

8/28/97 Recommendation of EPA/API/TMOGA Refinery Roundtable

(c) Compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is determined daily on a 7-day rolling average basis using the appropriate procedures outlined in § 60.106.

(d) A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days when complying with paragraph (b)(1) of this section.

[43 FR 10869, Mar. 15, 1978, as amended at 54 FR 34026, Aug. 17, 1989; 55 FR 40171, Oct. 2, 1990]

§ 60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fluid catalytic cracking unit catalyst regenerators subject to § 60.102(a)(2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity.

EPA has indicated that it has approved an alternative method of compliance with 60.105(a)(1) for a fluid catalytic cracking unit catalyst regenerator equipped with a wet gas scrubber. The alternate method requires the operator to continuously monitor:

- a) the pressure drop across the wet gas scrubber,
- b) the scrubber liquid to gas ratio (L/G), and
- c) the effluent temperature immediately downstream of the demister section of the control device.

4/26/91 EPA Memo from TSD to Region VI APTD

(2) For fluid catalytic cracking unit catalyst regenerators subject to § 60.103(a), an instrument for continuously monitoring and recording the concentration by

volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2)(ii) of this section.

(i) The span value for this instrument is 1,000 ppm CO.

(ii) A CO continuous monitoring system need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also files a written request for exemption to the Administrator and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that shall meet the requirements of Performance Specification 4 of Appendix B of this part. The span value shall be 100 ppm CO instead of 1,000 ppm and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in § 10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(3) For fuel gas combustion devices subject to § 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere (except where an H₂S monitor is installed under paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 50 ppm SO₂ and 10 percent oxygen (O₂).

(ii) The SO₂ monitoring level equivalent to the H₂S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 and 3 shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is

greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the S(2) emissions into the atmosphere from each of the combustion devices.

EPA has indicated that using a sample transport line from each of two crude oil heater stacks and a common SO₂ analyzer and electronic recorder will be acceptable under 60.105(a)(3) as long as each stack is sampled every 15 minutes, both stacks are tested simultaneously during the continuous monitor performance specification test, and all other requirements of 60.13 and 60.105 are met.

8/17/78 EPA Memo from DSSE to AFB

(4) In place of the SO(2) monitor in paragraph (a)(3) of this section, an instrument for continuously monitoring and recording the concentration (dry basis of H(2)S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H(2)S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H(2)S in the fuel gas being burned.

(iii) The performance evaluations for this H(2)S monitor under § 60.13(c) shall use Performance Specification 7. Method 11 shall be used for conducting the relative accuracy evaluations.

EPA has indicated that, under certain circumstances, it would waive, pursuant to 60.8(b)(4), the requirement for testing by Method 11 when the Tutwiler Method (UOP Method 9-59) indicates H₂S concentrations are well below the 0.10 grains/scf NSPS limit. Using the Tutwiler Method the needed accuracy was obtained by increasing the sample size from 100 ml to 500 ml..

8/27/76 EPA Letter from Region V AEB to Clark Oil & Refining

There have been some incidents of non-compliance resulting from calibration gas certificates, required by Section 4.3 of Performance Specification 7, being expired or not properly certified. It is recommended the operator use some method to insure that the certificates are properly certified and not expired. One such method is to make a contractual requirement with the supplier of the calibration gases to require the supplier tracks expiration dates and audits for proper certifications.

8/28/97 Recommendation of EPA/API/TMOGA Refinery Roundtable

EPA has indicated it would approve, as an alternate to the continuous monitoring method required in 60.105(a)(4), a method which includes the following provisions:

- a) sample the fuel gas every 8 hours using 3 Drager tubes for each sampling effort,
- b) submit quarterly summary reports indicating instances of H₂S concentrations between 1 and 5 ppm and the number of instances during which H₂S concentrations exceed 5 ppm, and
- c) maintain records on file for at least two years of the Drager tube monitoring results used to prepare the quarterly reports.

EPA would reconsider the approval of the alternate monitoring method if concentrations of H₂S did exceed 5 ppm.

4/9/96 EPA Letter from Region VI ATICB to AGE Refining, and
Undated EPA Memo from SSCD to Region IV APTMD found in TTNB

EPA has indicated it might approve, as an alternate to the continuous monitoring method required in 60.105(a)(4), a method using a sulfur balance for the fuel oil component of a dual-fuel combustion device.

3/8/82 EPA Memo from DSSE to AMD

There have been some incidents of non-compliance resulting from an operator failing to recognize that a dual-fuel system has been switched from natural gas to fuel gas. All potential fuel gas sources for a FGCD subject to Subpart J must meet the Subpart J limitation of 159 ppmv H₂S except during upsets, malfunctions, or startups and shutdowns related to planned maintenance per 60.8(c). It is recommended that operators insure that:
a) all supplies to a dual-fuel system that serves a FGCD subject to Subpart J meet the 159 ppmv H₂S limitation, or
b) use some method to insure that operators recognize when a dual-fuel system is switched to fuel gas and implement Subpart J-required compliance demonstration procedures. Equipping valves in a dual-fuel system to display changes in valve positions in a manned control room is a one method of making operators aware of fuel gas changes.

8/28/97 Recommendation of EPA/API/TMOGA Refinery Roundtable

5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to § 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

- (i) The span values for this monitor are 500 ppm SO(2) and 10 percent O(2).
 - (ii) The performance evaluations for this SO(2) monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 and 3 shall be used for conducting the relative accuracy evaluations.
- (6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to § 60.104(a)(2)(ii), an instrument for continuously monitoring and recording the concentration of reduced sulfur and O(2) emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO(2) (dry basis, zero percent excess air).
 - (i) The span values for this monitor are 450 ppm reduced sulfur and 10 percent O(2).
 - (ii) The performance evaluations for this reduced sulfur (and O(2)) monitor under § 60.13(c) shall use Performance Specification 5, except the calibration drift specification is 2.5 percent of the span value rather than 5 percent. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields O(2) concentrations below 0.25 percent during the performance specification test, the O(2) concentration may be assumed to be zero and the reduced sulfur CEMS need not include an O(2) monitor.
- (7) In place of the reduced sulfur monitor under paragraph (a)(6) of this section, an instrument using an air or O(2) dilution and oxidation system to convert the reduced sulfur to SO(2) for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant SO(2). The monitor shall include an oxygen monitor for correcting the data for excess oxygen.
 - (i) The span values for this monitor are 375 ppm SO(2) and 10 percent O(2).
 - (ii) For reporting purposes, the SO(2) exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ (and O₂) monitor under § 60.13(c) shall use Performance Specification 5. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations.

(8) An instrument for continuously monitoring and recording concentrations of sulfur dioxide in the gases at both the inlet and outlet of the sulfur dioxide control device from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1). The span value of the inlet monitor shall be set at 125 percent of the maximum estimated hourly potential sulfur dioxide emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential sulfur dioxide emission concentration entering the control device.

(9) An instrument for continuously monitoring and recording concentrations of sulfur dioxide in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 50 vppm emission limit under § 60.104(b)(1). The span value of the monitor shall be set at 50 percent of the maximum hourly potential sulfur dioxide emission concentration entering the control device.

(10) An instrument for continuously monitoring and recording concentrations of oxygen (O₂) in the gases at both the inlet and outlet of the sulfur dioxide control device (or the outlet only if specifically complying with the 50 vppm standard) from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator has elected to comply with § 60.104(b)(1). The span of this continuous monitoring system shall be set at 10 percent.

(11) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(12) The owner or operator shall follow appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests, for the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section.

(13) When seeking to comply with § 60.104(b)(1), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days.

- (i) The test methods as described in § 60.106(k);
- (ii) A spare continuous monitoring system; or
- (iii) Other monitoring systems as approved by the Administrator.

(b) [Reserved]

(c) The average coke burn-off rate (thousands of kilograms per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102 or § 60.103, or § 60.104(b)(2).

(d) For any fluid catalytic cracking unit catalyst regenerator under § 60.102 that uses an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil-fuels (liters/hr or kg/hr) and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

NOTE: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(1) Opacity. All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under § 60.105(a)(1) exceeds 30 percent.

(2) Carbon monoxide. All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under § 60.105(a)(2) exceeds 500 ppm.

(3) Sulfur dioxide from fuel gas combustion.

(i) All rolling 3-hour periods during which the average concentration of SO(2) as measured by the SO(2) continuous monitoring system under § 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of H(2)S as measured by the H(2)S continuous monitoring system under § 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) Sulfur dioxide from Claus sulfur recovery plants.

(i) All 12-hour periods during which the average concentration of SO(2) as measured by the SO(2) continuous monitoring system under § 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as SO(2)) as measured by the reduced sulfur continuous monitoring system under § 60.105(a)(6) exceeds 300 ppm; or

(iii) All 12-hour periods during which the average concentration of SO(2) as measured by the SO(2) continuous monitoring system under § 60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air).

[39 FR 9315, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975; 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10869, Mar. 15, 1978; 48 FR 23611, May 25, 1983 50 FR 31701, Aug. 5, 1985; 51 FR 31701, July 1, 1986; 54 FR 34026, Aug. 17, 1989; 55 FR 40171, Oct. 2, 1990]

§ 60.106 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the particulate matter (PM) standards in § 60.102(a) as follows:

(1) The emission rate (E) of PM shall be computed for each run using the following equation:

$$E = \frac{K \, c(s) \, Q(sd)}{R(c)}$$

where:

E = Emission rate of PM, kg/1000 kg (lb/1000 lb) of coke burn-off.

c(s) = Concentration of PM, g/dscm (lb/dscf).

Q(sd) = Volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

R(c) = Coke burn-off rate, kg coke/hr (1000 lb coke/hr).

K = Conversion factor, 1.0 (kg[2]/g)/(1000 kg) [10[3] lb/(1000 lb)].

(2) Method 5B or 5F is to be used to determine particulate matter emissions and associated moisture content from affected facilities without wet FGD systems; only Method 5B is to be used after wet FGD systems. The sampling time and sample volume for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) The coke burn-off rate (R(c)) shall be computed for each run using the following equation:

$$R(c) = \frac{K(1)Q(r) (\%CO(2) + \%CO)K(2)Q(a)-K(3)Q(r)}{[(\%CO/2+\%CO(2)+\%O(2))]}$$

where:

R(c) = Coke burn-off rate, kg/hr (1000 lb/hr).

Q(r) = Volumetric flow rate of exhaust gas from catalyst regenerator before entering the emission control system, dscm/min (dscf/min).

Q(s) = Volumetric flow rate of air to FCCU regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

%CO(2) = Carbon dioxide concentration, percent by volume (dry basis).

%CO = Carbon monoxide concentration, percent by volume (dry basis).

%O(2) = Oxygen concentration, percent by volume (dry basis).

K(1) = Material balance and conversion factor, $0.2982 \text{ (kg-min)/(hr-dscm-}\% \text{)[0.0186 (lb-min)/(hr-dscf-}\% \text{)]}$.

K(2) = Material balance and conversion factor, $2.088 \text{ (kg-min)/(hr-dscm-}\% \text{)[0.1303 (lb-min)/(hr-dscf-}\% \text{)]}$.

K(3) = Material balance and conversion factor, $0.0994 \text{ (kg-min)/(hr-dscm-}\% \text{)[0.0062 (lb-min)/(hr-dscf-}\% \text{)]}$.

(i) Method 2 shall be used to determine the volumetric flow rate (Q(r)).

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3 shall be used to determine CO(2), CO(1) and O(2) concentrations.

(4) Method 9 and the procedures of § 60.11 shall be used to determine opacity.

(c) If auxiliary liquid or solid fossil-fuels are burned in an incinerator-waste heat boiler, the owner or operator shall determine the emission rate of PM permitted in § 60.102(b) as follows:

(1) The allowable emission rate (E(s)) of PM shall be computed for each run using the following equation:

$$E(s) = 1.0 + A (H/R(c))K'$$

where:

E(s) = Emission rate of PM allowed, kg/1000 kg (lb/1000 lb) of coke burn-off in catalyst regenerator.

1.0 = Emission standard, kg coke/1000 kg (lb coke/1000 lb).

A = Allowable incremental rate of PM emissions, 0.18 g/million cal (0.10 lb/million Btu).

H = Heat input rate from solid or liquid fossil fuel, million cal/hr (million Btu/hr).

$R(c)$ = Coke burn-off rate, kg coke/hr (1000 lb coke/hr).

K' = Conversion factor to units of standard, 1.0 (kg[2]/g)/(1000 kg) [10[3] lb/(1000 lb)].

(2) Procedures subject to the approval of the Administrator shall be used to determine the heat input rate.

(3) The procedure in paragraph (b)(3) of this section shall be used to determine the coke burn-off rate ($R(c)$).

(d) The owner or operator shall determine compliance with the CO standard in § 60.103(a) by using the integrated sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(e) The owner or operator shall determine compliance with the H(2)S standard in § 60.104(a)(1) as follows: Method 11 shall be used to determine the H(2) concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H(2)S may necessitate sampling for longer periods of time.

(f) The owner or operator shall determine compliance with the SO(2) and the H(2)S and reduced sulfur standards in § 60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the SO(2) concentration. The concentration in mg/dscm (lb/dscf) obtained by Method 6 is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m² (54 ft²) or at a point no closer to the walls than 1.00 m (39 in.) if the cross-sectional area is 5.00 m² or more and the centroid is more than 1 m from the wall. The

sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and H(2)S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO(2) equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO(2) equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3. The samples shall be taken simultaneously with the SO(2), reduced sulfur and H(2)S, or moisture samples. The SO(2), reduced sulfur, and H(2)S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(3) of this section.

(g) Each performance test conducted for the purpose of determining compliance under § 60.104(b) shall consist of all testing performed over a 7-day period using the applicable test methods and procedures specified in this section. To determine compliance, the arithmetic mean of the results of all the tests shall be compared with the applicable standard.

(h) For the purpose of determining compliance with § 60.104(b)(1), the following calculation procedures shall be used:

(1) Calculate each 1-hour average concentration (dry, zero percent oxygen, vppm) of sulfur dioxide at both the inlet and the outlet to the add-on control device as specified in § 60.13(h). These calculations are made using the emission data collected under § 60.105(a).

(2) Calculate a 7-day average (arithmetic mean) concentration of sulfur dioxide for the inlet and for the outlet to the add-on control device using all of the 1-hour average concentration values obtained during seven successive 24-hour periods.

(3) Calculate the 7-day average percent reduction using the following equation:

$$R(\text{so}(2)) = 100[C(\text{so}(2))((i)) -$$

$$C(\text{so}(2))((o))]/C(\text{so}(2))((i))$$

where:

$R(\text{so}(2))$ = 7-day average sulfur dioxide emission reduction, percent

$C(\text{so}(2))((i))$ = sulfur dioxide emission concentration determined in § 60.196(f)(2) at the inlet to the add-on control device, vppm

$C(\text{so}(2))((o))$ = sulfur dioxide emission concentration determined in § 60.106(f)(2) at the outlet to the add-on control device, vppm

100 = conversion factor, decimal to percent (4) Outlet concentrations of sulfur dioxide from the add-on control device for compliance with the 50 vppm standard, reported on a dry, O₂-free basis, shall be calculated using the procedures outlined in § 60.106(h)(1) and (2) above, but for the outlet monitor only.

(5) If supplemental sampling data are used for determining the 7-day averages under paragraph (h) of this section and such data are not hourly averages, then the value obtained for each supplemental sample shall be assumed to represent the hourly average for each hour over which the sample was obtained.

(6) For the purposes of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$$C(\text{adj}) = C(\text{meas}) [20.9(c)/(20.9 - \%O(2))]$$

where:

$C(\text{adj})$ = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm

$C(\text{meas})$ = pollutant concentration measured on a dry basis, ppm or g/dscm

$20.9(c)$ = 20.9 percent oxygen -- 0.0 percent oxygen (defined oxygen correction basis), percent

20.9 = oxygen concentration in air, percent

$\%O(2)$ = oxygen concentration measured on a dry basis, percent

(i) For the purpose of determining compliance with § 60.104(b)(2), the following reference methods and calculation procedures shall be used except as provided in paragraph (i)(12) of this section:

(1) One 3-hour test shall be performed each day.

(2) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 8 as modified in § 60.106(i)(3) for the concentration of sulfur oxide calculated as sulfur dioxide and moisture content,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 calculation procedures (data obtained from Methods 3 and 8) for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) Method 8 shall be modified by the insertion of a heated glass fiber filter between the probe and first impinger. The probe liner and glass fiber filter temperature shall be maintained above 160°C (320°F). The isopropanol impinger shall be eliminated. Sample recovery procedures described in Method 8 for

container No. 1 shall be eliminated. The heated glass fiber filter also shall be excluded; however, rinsing of all connecting glassware after the heated glass fiber filter shall be retained and included in container No. 2. Sampled volume shall be at least 1 dscm.

(4) For Method 3, the integrated sampling technique shall be used.

(5) Sampling time for each run shall be at least 3 hours.

(6) All testing shall be performed at the same location. Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator-waste heat boiler in which auxiliary or supplemental gaseous, liquid, or solid fossil fuel is burned, testing shall be conducted at a point between the regenerator outlet and the incinerator-waste heat boiler. An alternative sampling location after the waste heat boiler may be used if alternative coke burn-off rate equations, and, if requested, auxiliary/supplemental fuel SO(x) credits, have been submitted to and approved by the Administrator prior to sampling.

(7) Coke burn-off rate shall be determined using the procedures specified under paragraph (b)(3) of this section, unless paragraph (i)(6) of this section applies.

(8) Calculate the concentration of sulfur oxides as sulfur dioxide using equation 8-3 in Section 6.5 of Method 8 to calculate and report the total concentration of sulfur oxides as sulfur dioxide (C(so)(x)).

(9) Sulfur oxides emission rate calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$E(\text{so}(x)) = C(\text{so}(x)) Q(\text{sd})/1,000$$

where:

$E(\text{so}(x))$ = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr

$C(\text{so}(x))$ = sulfur oxides emission concentration calculated as sulfur dioxide, g/dscm

$Q(sd)$ = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr

1,000 = conversion factor, g to kg

(10) Sulfur oxides emissions calculated as sulfur dioxide per 1,000 kg coke burn-off in the fluid catalytic cracking unit catalyst regenerator shall be determined for each test run by the following equation:

$$R(so(x)) = (E(so(2)))/R(c)$$

where:

$R(so(x))$ = sulfur oxides emissions calculated as sulfur dioxide, kg/1,000 kg coke burn-off

$E(so(x))$ = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr

$R(c)$ = coke burn-off rate, 1,000 kg/hr (11) Calculate the 7-day average sulfur oxides emission rate as sulfur dioxide per 1,000 kg of coke burn-off by dividing the sum of the individual daily rates by the number of daily rates summed.

(12) An owner or operator may, upon approval by the Administrator, use an alternative method for determining compliance with § 60.104(b)(2), as provided in § 60.8(b). Any requests for approval must include data to demonstrate to the Administrator that the alternative method would produce results adequate for the determination of compliance.

(j) For the purpose of determining compliance with § 60.104(b)(3), the following analytical methods and calculation procedures shall be used:

(1) One fresh feed sample shall be collected once per 8-hour period.

(2) Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods: ASTM D129-64 (Reapproved 1978),

ASTM D1552-83, ASTM D2622-87, or ASTM D1286-87. (These methods are incorporated by reference: see § 60.17.) The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Administrator.

(3) If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:

(i) Individual samples shall be collected once per 8-hour period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.

(ii) Each fresh feed sample shall be analyzed separately using the methods specified under paragraph (j)(2) of this section.

(iii) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S(f) = \text{SUM}_{i=1}^n \frac{S(i)Q(i)}{Q(f)}$$

where:

$S(f)$ = fresh feed sulfur content expressed in percent by weight of fresh feed.

n = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

$Q(f)$ = total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

$S(i)$ = fresh feed sulfur content expressed in percent by weight of fresh feed for the "ith" sampling location.

$Q(i)$ = volumetric flow rate of fresh feed stream for the "ith" sampling location.

- (4) Calculate a 7-day average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven successive 24-hour periods.
- (k) The test methods used to supplement continuous monitoring system data to meet the minimum data requirements in § 60.104(d) will be used as described below or as otherwise approved by the Administrator.
- (1) Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the monitor.
 - (2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. A minimum of 18 valid samples is required to obtain one valid day of data.
 - (3) For Method 6B, collection of a sample representing a minimum of 18 hours is required to obtain one valid day of data.
 - (4) For Method 8, the procedures as outlined in this section are used. The equivalent of 16 hours of sampling is required to obtain one valid day of data.

[39 FR 9315, Mar. 8, 1974, as amended at 42 FR 32427, June 24, 1977; 43 FR 10869, Mar. 15, 1978; 52 FR 20932, June 1, 1987; 52 FR 32027, Aug. 25, 1987; 53 FR 41333, Oct. 21, 1988; 54 FR 34026, Aug. 17, 1989; 55 FR 40171, Oct. 2, 1990; 56 FR 4176, Feb. 4, 1991]

§ 60.107 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to § 60.104(b) shall notify the Administrator of the specific provisions of § 60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by § 60.7(a)(3). If an owner or operator elects at a later date to comply with an alternative provision of § 60.104(b), then the Administrator shall be notified by the owner or operator in the quarterly (or semiannual) report described in paragraphs (c) and (d) of this section for the quarter during which the change occurred.

(b) Each owner or operator subject to § 60.104(b) shall record and maintain the following information:

(1) If subject to § 60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to § 60.105(a)(13) and § 60.106(k)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to § 60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if § 60.106(i)(12) applies.

(3) If subject to § 60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each owner or operator subject to § 60.104(b) shall submit a report each quarter except as provided by paragraph (d) of this section. The following information shall be contained in each quarterly report:

- (1) Any 7-day period during which:
- (i) The average percent reduction and average concentration of sulfur dioxide on a dry, O₂-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1) is below 90 percent and above 50 vppm, as measured by the continuous monitoring system prescribed under § 60.105(a)(8), or above 50 vppm, as measured by the outlet continuous monitoring system prescribed under § 60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under § 60.106(h);
 - (ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(2) exceeds 9.8 kg SO_x per 1,000 kg coke burn-off, as measured by the daily testing prescribed under § 60.106(i). The average emission rate shall be determined using the procedures specified under § 60.106(i); and
 - (iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with § 60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under § 60.106(j).
- (2) Any 30-day period in which the minimum data requirements specified in § 60.104(d) are not obtained.
- (3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:
- (i) The date that the exceedance occurred;
 - (ii) An explanation of the exceedance;
 - (iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and
 - (iv) A description of the corrective action taken, if any.

- (4) If subject to § 60.104(b)(1),
- (i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;
 - (ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;
 - (iii) Identification of times when hourly averages have been obtained based on manual sampling methods;
 - (iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and
 - (v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.
 - (vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.
- (5) If subject to § 60.104(b)(2), for each day in which a Method 8 sample result was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by the Administrator. (6) If subject to § 60.104(b)(3), for each 8-hour shift in which a feed sulfur measurement was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Administrator.
- (d) If no exceedances (as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section) occur in a quarter, and if the owner or operator has not changed the standard under § 60.104(b) under which compliance is obtained, then the owner or operator may submit a semiannual report in which a statement is included that states that no exceedances had occurred during the affected quarter(s). If the owner or operator elects to comply with an alternative provision of § 60.104(b), a quarterly report must be submitted for the quarter during which a change occurred.

(e) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operation of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(f) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

[54 FR 34026, Aug. 17, 1989 as amended at 55 FR 40171, Oct. 2, 1990; 58 FR 18014, April 7, 1993, 58 FR 34369, June 25, 1993]

§ 60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in § 60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under § 60.104(b). Performance tests conducted for the purpose of determining compliance under § 60.104(b) shall be conducted according to the applicable procedures specified under § 60.106.

(b) Owners or operators who seek to comply with § 60.104(b)(3) shall meet that standard at all times, including periods of startup, shutdown, and malfunctions.

(c) The initial performance test shall consist of the initial 7-day average calculated for compliance with § 60.104(b)(1), (b)(2), or (b)(3).

(d) After conducting the initial performance test prescribed under § 60.8, the owner or operator of a fluid catalytic cracking unit catalyst regenerator subject to § 60.104(b) shall conduct a performance test for each successive 24-hour period thereafter. The daily performance tests shall be conducted according to the appropriate procedures specified under § 60.106. In the event that a sample collected under § 60.106(i) or (j) is accidentally lost or conditions occur in which one of the samples must be discontinued

because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operators' control, compliance may be determined using available data for the 7-day period.

(e) Each owner or operator subject to § 60.104(b) who has demonstrated compliance with one of the provisions of § 60.104(b) but at a later date seeks to comply with another of the provisions of § 60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of § 60.104(b). The owner or operator shall furnish the Administrator a written notification of the change in a quarterly report that must be submitted for the quarter in which the change occurred.

[54 FR 34026, Aug. 17, 1989, as amended at 55 FR 40171, Oct. 2, 1990]

§ 60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which shall not be delegated to States:

- (1) Section 60.105(a)(13)(iii),
- (2) Section 60.106(i)(12).

[54 FR 34026, Aug. 17, 1989, as amended at 55 FR 40171, Oct. 2, 1990]